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STUDY DOCUMENT NUMBER 6. CONTROL STRATEGY SELECTION AND COST ESTIMATES FOR UTILITIES

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16. ABSTRACT

This report is the sixth volume in support of the Inflation Impact Statement for sulfur dioxide regulations prepared by the U.S. Environmental Protection Agency, to correct deficiencies in the Ohio State Implementation Plan. The Technical Support Document, Volumes I and II may be obtained through the National Technical Information Service - EPA 905/2-76-002, PB-257 694 and PB-257 695.

This document presents a summary of the methodology used to estimate control strategies selected by the utilities and associated costs of implementing these strategies. Cost minimization models are discussed along with the mix of controls that might be expected to result in compliance. Capital and annual costs are presented as part of the sensitivity analysis.

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Control Strategy Selection and Cost Estimates for Utilities

Part of a study of the Economic Impact of Sulfur Regulations promulgated by the U.S. Environmental Protection Agency for Ohio on August 27, 1976.

Prepared for:

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United States Environmental Protection Agency

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SECTION I

INTRODUCTION

This report represents the methodology utilized to determine the control strategies utility companies in Ohio would be likely to select to comply with sulfur oxide regulations developed by the United States Environmental Protection Agency (USEPA). This report is one of a series of ten documents which comprise the analysis of the economic and financial impact of regulations for Ohio promulgated by USEPA on August 27, 1976. Appendix A describes the relationship of this report to other study documents.

Section II contains of brief summary of the methodology used to estimate control strategies selected by the utilities and the associated costs of implementing these strategies.

Section III outlines in greater detail the methodology employed to determine the minimum cost mode of compliance. Section IV presents a detailed discussion of the factors considered in estimating costs for each control alternative and key equations of the cost minimization model.

Section V presents the mix of control strategies that utilities might be expected to select to comply with sulfur oxide regulations. Capital and annual costs associated with these strategies are also presented.

Section VI contains the results of sensitivity analyses which were performed during the preparation of the utility economic impact analysis. The first analysis was designed to show the sensitivity of utility control costs to alternative sets of regulations. This analysis provided the basis for a recommendation that allowing stack specific emission limits to differ within

plants would reduce the costs of achieving air quality standards. The second analysis was designed to show the sensitivity of control strategy selection and costs to a different estimate of FGD costs. Finally, the third analysis illustrates the sensitivity of cost estimates when certain assumptions are relaxed to allow the plant to use more than one quality of coal.

SECTION II

EXECUTIVE SUMMARY

This report describes the methodology used in the selection of control strategies and calculation of control costs. Also presented are the cost minimization model outputs on control strategy selection and associated costs to comply with sulfur oxide regulations. Finally, results of several cost sensitivity analyses are discussed.

A. Methodology for Control Strategy Selection

The analytical steps in estimating the mix and costs of control strategies are shown in Figure 2-1. The cost minimization model uses the input data provided in backup reports to select for each affected coal fired power plant the likely control strategy, and presents control costs and the energy implications of the selected approach. Key elements in the logic of the strategy selection process include:

- minimizing discounted cash flow of control costs
- selection of optimal control strategy subject to plant wide constraints
- generating estimates of control costs and energy impacts for each plant

The factors taken into account in the cost algorithms are summarized in Table II-1 for each control strategy.

B. Control Strategy Selection and Costs

Nearly all of the 21,500 megawatts of utility capacity is out of compliance under the proposed regulations while only 53 percent is expected to be out of compliance under the final regulations. Table II-2 indicates that under both the proposed and final regulations roughly equal reliance is placed on the alter-

Figure 2-1

Methodology - Utilities

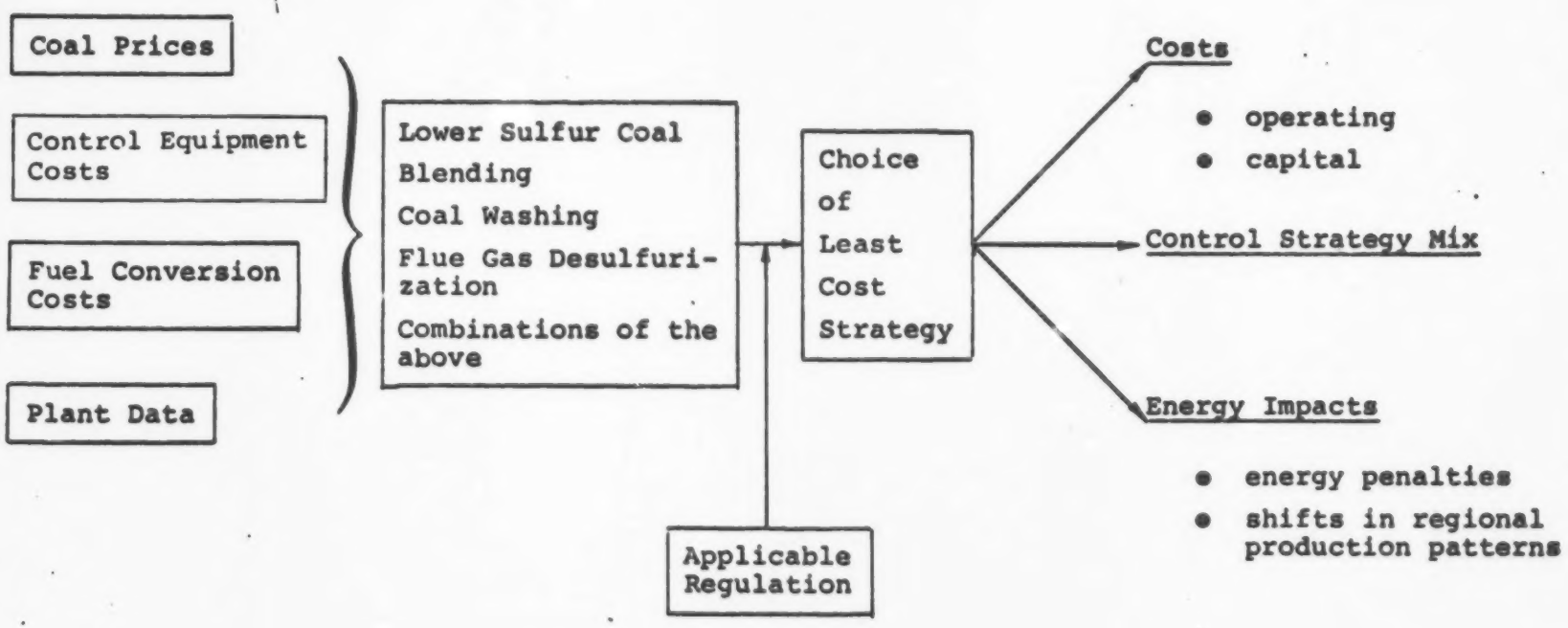

Table II-1

Factors Influencing Costs

Common to All Control Options (stack specific)

- remaining life
- design capacity
- firing rate
- existing sulfur content
- capacity utilization rate
- coal consumption
- applicable regulation
- existing coal price
- plant size

Low Sulfur Coal

- boiler or pulverizer modifications
- boiler derate
- particulate control equipment
- power penalty of particulate control requirement
- price of low sulfur coal

Flue Gas Desulfurization

- two systems evaluated (Wellman-Lord and Lime/limestone)
- power penalty
- steam penalty
- sludge removal
- plant economies of scale
- degree of sulfur removal required

Blending

- same as low sulfur coal
- blending facility costs
- blending facility power penalty

Table II-1 (cont'd)

Coal Cleaning (at the plant)

source of coal
degree sulfur removal required
coal energy losses
plant size
power penalty

Combination Options

all of the above

TABLE II-2

ANTICIPATED CONTROL STRATEGY SELECTION BY
MAJOR COAL FIRED POWER PLANTS
OF INVESTOR-OWNED UTILITIES

(Percents of Capacity)

Control Strategy[1/]	Proposed Regulations	Final Regulations
Flue Gas Desulfurization	39%	23%
Low Sulfur Coal or Blending	42%	29%
FGD Plus Lower Sulfur Coal	14%	1%
Out of Compliance	95%	53%
In Compliance	5%	47%

1/ Where FGD is selected, the megawatt capacity reflects those units requiring some use of FGD. The actual megawatts of scrubbing equipment required depends upon the degree of emission reduction required and will be less than the rated megawatt capacity.

natives of flue gas desulfurization and switching to lower sulfur content coal.

The capital costs and the annual increase in consumer charges shown in Table II-3 reflect the significant cost reductions brought about by refinements of the final regulations compared to the proposed regulations. Especially significant is the reduction in capital requirements of two-thirds or nearly $1 billion.

C. Sensitivity Analyses

This section presents the results of several sensitivity analyses on the costs of compliance with sulfur regulations. The first special study is a comparison of costs for a sample of Ohio plants under two forms of regulations:

- a conventional flat regulation where all stacks at the plant are subject to the same emission limit
- a more flexible regulation which allows utilities to adopt compliance strategies keyed to emission limits which differ among stacks subject to an overall constraint which ensures achievement of ambient air quality standards

Results of this analysis for the sample of plants indicates that a flexible regulation can reduce the annual costs of achieving air quality standards by 23 percent and capital costs by 30 percent. These results suggest that the flexible form of regulation applicable to isolated sources would realize a significant reduction in the cost of achieving air quality goals.

The second special study evaluates the effects on control strategy selection and costs of compliance if much higher unit cost estimates of flue gas desulfurization (FGD) were used. The analysis suggests that if FGD costs were higher than these employed in this study, a higher electricity price increase would

TABLE II-3

ELECTRIC UTILITIES

COSTS OF SULFUR OXIDE REGULATIONS

(Millions of 1975 Dollars)

Alternatives	Total Increase in Capital Costs (1976-1979)	Required Increase in Annual Revenues in 1980
Proposed	1480	354
Final	542	130
Cost Reduction	938	224

1/ The above costs include only investor-owned utilities. Costs for municipal systems were estimated at $24 million of capital expenditures and a $3 million annual cost increase.

occur along with lesser reliance on FGD.

The final study illustrates that a key assumption in the cost minimization model can significantly overstate the costs of compliance. If the assumption used in the model forcing all stacks in a plant to use the same quality coal were relaxed, costs and the resultant economic impacts would probably be significantly lower than the study estimates.

SECTION III

COST ESTIMATION METHODOLOGY

A. Criteria for Choice of Compliance Alternative

The selection of the control strategy to comply with applicable regulations is based on the criterion of minimizing the annual costs of control. Annual costs include annual capital charges, operating costs of pollution control equipment, and the net increase in fuel costs. The concept of annual cost in this study is equivalent to an increase in utility operating revenues required to cover the costs of compliance with sulfur oxide regulations. Consequently, cost minimization amounts to a criterion of selecting that control strategy which minimizes the increase in electricity rates over the life of the affected installation.

Logically, application of this criterion would take the form of minimizing the discounted stream of annual increases in annual costs (or operating revenues) over the remaining life of the installation. Due to resource constraints placed on this study, a method of approximating this discounting procedure was adopted. Comparisons of control strategies were based on annual costs in the year 1985. [1/] Using 1985 as the point of comparison differs from

---

1/ 1985 was selected as the approximate mid-point in the relevant time horizon, assuming the discounting period was 20 years reflecting the useful life of pollution control equipment.

a comparison in 1975 dollars in the following respects. First, it allows for differences in the expected rates of inflation between operating costs of capital intensive control options (e.g. flue gas desulfurization) and coal costs that would be incurred in strategies relying on low sulfur coal. If coal prices are expected to escalate faster than labor and materials costs required to operate flue gas desulfurization (FGD), then FGD would appear as a less costly option relative to low sulfur coal in 1985 prices than it would in a comparison of 1975 costs. Second, the use of 1985 tends to favor capital intensive control options such as FGD. This is because capital equipment will be purchased in the 1976-79 period then included in the utility rate base at the installed price. Control approaches relying on low sulfur coal, on the other hand, will tend to escalate each year with the general level of coal prices. Thus, using 1985 as a basis of comparison amounts to a comparison of capital costs in 1976-79 dollars with fuel costs in 1985 dollars. While the use of 1985 tends to favor FGD over low sulfur coal for this reason, this approach was felt to approximate utility rate making procedures where capital is costed at purchase price and fuel cost increases are passed directly through to consumers each year.

This approach to utility decisions on control strategy selection assumes that utilities are able to finance the necessary investment expenditures without affecting the cost of capital or the general financial viability of the utility system. In practice a utility system may find that the investments required by a FED strategy cannot be financed without undesirable changes in such parameters as debt/equity or interest coverage ratios. In these circumstances, the utility would reevaluate its control selection inserting a higher cost for capital intensive approaches. This study does not

account for the effects of financing difficulties in the control strategy selection process but does review the financial impacts in the discussion on Economic and Financial Impacts on Utilities (document #3). It should be emphasized, however, that utilities which might experience financial problems will tend to adopt less capital intensive control strategies thus reducing financial burdens at the expense of higher consumer charges for electricity.

A utility may also opt to speed up the scheduled date of retirement for older plants in order to avoid incurring the capital costs of compliance. This last alternative was not considered in this study.

B. Optimization Model

1. Level of Analysis

Control strategies are selected for each coal fired power plant subject to sulfur emission regulations. The basic unit of cost analysis is the stack for the following reasons:

- regulations are applied to each power plant stack and, consequently, may be of varying degrees of stringency among stacks in the same plant
- costs of control to achieve the same emission level differ among stacks due to variations in the size of the unit, type of boiler, age, capacity utilization and physical configuration of the boilers feeding into common stacks

2. Control Alternatives Considered

a. Low sulfur coal

The plant was allowed to switch from its current sources of coal supplies to a source of lower sulfur coal. Each plant could select from seven coal supply regions the least cost

complying coal.[1] The plant was allowed to select only one source of new coal supplies.[2]

b. Blending

The plant was allowed to purchase new supplies of low or medium sulfur coal which would be blended with current supplies to satisfy sulfur emission limits.

c. Coal washing

An option was included which allowed the power plant to install a coal washing facility on-site to improve the sulfur content of its current fuel supplies. Coal washing was also taken into account in developing new coal supplies, although in this case processing facilities would be sited near producing mines.[3]

d. Flue Gas Desulfurization

The plant was allowed to apply either of two FGD systems to its current coal supplies in order to satisfy regulations. One system was the wet limestone throwaway process (which generates a sludge) and a regenerable FGD system which produces a saleable product, such as elemental sulfur, rather than a sludge.

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[1] Document #10, Coal Prices, describes the derivation of the matrix of coal sources reflecting delivered prices to the plant. The matrix potentially contains 42 elements: 6 sulfur content classes from 7 supply regions.

[2] In fact, a plant is likely to select several sources of low sulfur coal supplies in order to reduce its reliance on any one supplier. So long as the delivered price of alternative sources is similar, no bias is introduced into the analysis. Utilities may be willing to incur higher fuel costs by diversifying supplier sources in order to insure reliability.

[3] See documents #8 and #10 for detailed discussions of coal washing.

e. Combination Options

In addition to the basic control strategies outlined above, the plant could select among the following options:

- FGD and coal blending
- FGD and low sulfur coal
- FGD and washed coal

3. Constraints Imposed on Utility Control Strategy Selection Procedures

The cost of each of the options described above was calculated for each plant subject to plantwide assumptions regarding the level of electricity generation and the number of coal piles permitted at the plant. These two assumptions are critical to the analysis and both tend to overstate the actual costs of compliance.

a. Electricity generation

All stacks in the plants covered in the study are assumed to continue to generate the same amount of electricity as in 1974-75. This assumption was necessary in the absence of knowledge of both the planned operating schedules over the next 10-15 years for these units and the extent to which these schedules could be adjusted by the utilities to reduce the costs of compliance with sulfur oxide regulations. This assumption overstates the costs of compliance since no allowances are made:

- for the expected decline in operating and fuel costs as these plants are phased out and new power plants come on line,[1]
- for any shifts in capacity utilization the utility might make among its plants to reduce reliance on plants subject to relatively high control costs.

1/ New plants would be subject to the Federal New Source Performance Standards and are not covered in the regulations promulgated by the USEPA on August 27, 1976.

b. Coal pile limitations

Utilities typically receive coal from many supply sources which are dumped on one coal pile. Coal is transferred from this pile and fed into the pulverizers and boilers. Although occasionally more than one coal pile is utilized, there has been no reason for utilities to establish separate coal piles for each stack or combination of stacks. Assuming the existence of one coal pile essentially forces all stacks to utilize the same sulfur content coal. Thus, in a plant which has 3 stacks but only is out of compliance, the selection of low sulfur coal means that higher fuel costs must be incurred at all 3 stacks. Actually, it may be cheaper for such a plant to establish a new coal pile feeding low sulfur coal into the single out of compliance stack. Since time constraints did not allow plant specific reviews of space availability and the costs of maintaining multiple coal piles, the cost estimates in this study are based on the assumption of one coal pile for each plant.

This assumption tends to overstate costs and to bias the analysis in favor of FGD compared to low sulfur coal. The analytical model employed is capable of evaluating control options where multiple coal piles are permitted. An illustration of the cost savings achieved when the one coal pile assumption is dropped is contained in Section VI.

4. Optimization algorithm

The choice of the least cost method of compliance is conceptually a linear or integer programming problem. Due to time constraints and the large data base, [1/] the problem was solved using a conventional search algorithm which evaluates the cost of each option, then compares

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[1/] Each stack has approximately 200 data points.

to select the least cost choice.[1/]

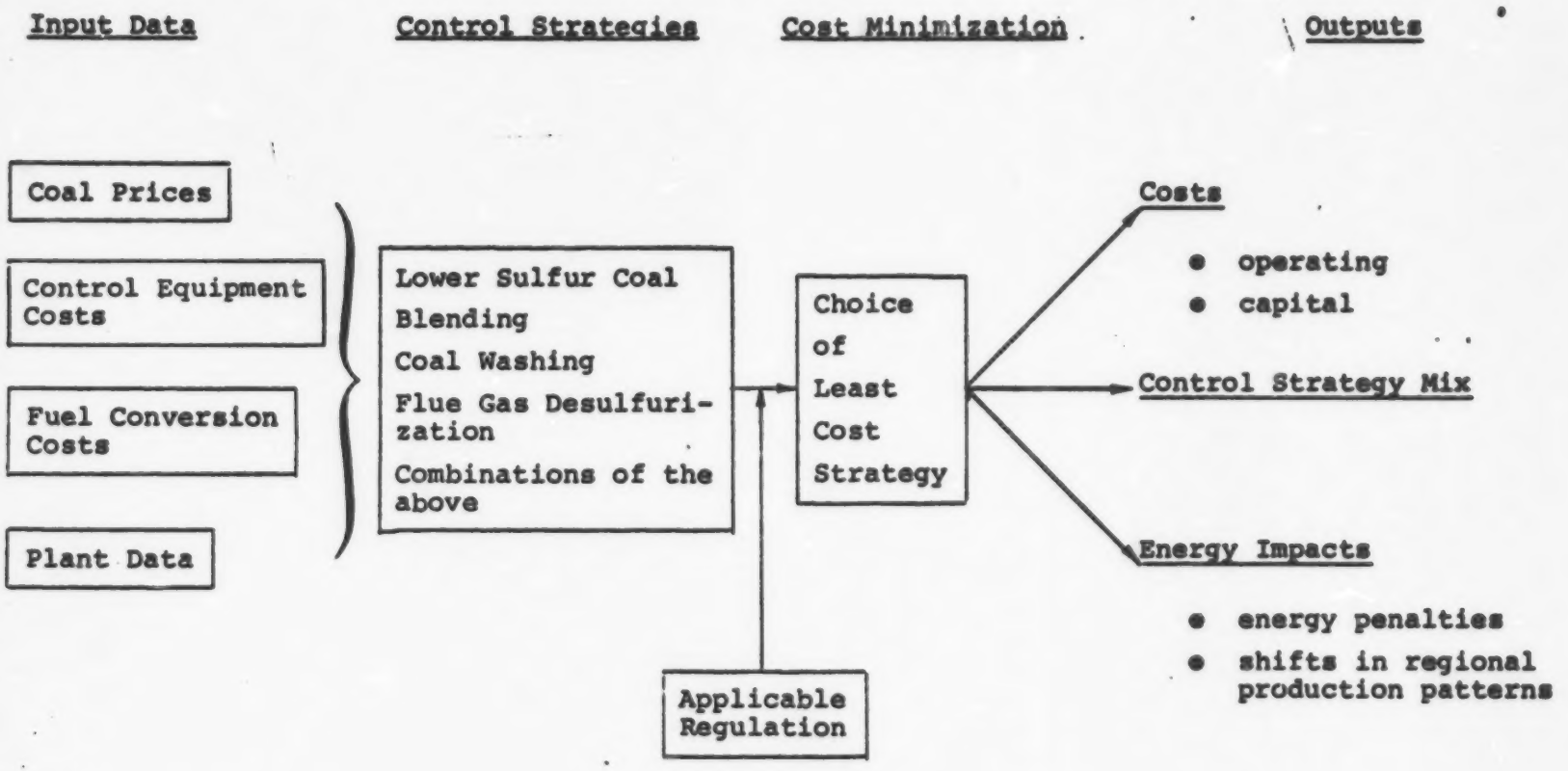
The methodology of control strategy selection is depicted in a summary form in Figure 3-1 which shows the steps leading to generation of three sets of outputs from the cost minimization model:

- incremental capital and operating costs of compliance
- the mix of control strategies selected
- the energy implications of the control strategies selected

1/ Actually only two aspects of control strategy selection warrant the application of linear of integer programming: the combination control options and the multiple coal pile case. These cases were solved using iterative search techniques.

Figure 3-1

Methodology - Utilities



See Figure 2-1

Section IV

COSTS OF CONTROL ALTERNATIVES

A. Introduction

This section presents the detailed discussion of the factors considered and the equations used to calculate the costs of each alternative control option.

Aspects which are common to all contro strategies are presented first followed by the cost algorithms for each control alternative.

B. Aspects Common to All Control Strategies

1. Cost Curves

Basic cost data for pollution control equipment for the utility sector was provided for three hypothetical regulations.[1/] Costs for other regulations were obtained by interpolating between the three data points. An illustration of such a cost curve is depicted in Figure 4-1 for capital costs of FGD for one stack. The highest emission rate reflects the average sulfur content of current quality coal, shown as 4 #SO_2/MMBTU. The most stringent regulation value of 1 #SO_2/MMBTU was set by the stack specific regulation implied by the regulations proposed in November, 1975 by USEPA for Ohio power plants. Two intermediate points between these extremes were selected (2 and 3 #SO_2/MMBTU) which were 1/3 and 2/3's of the difference between the existing fuel quality and the proposed regulations. Costs for other values,

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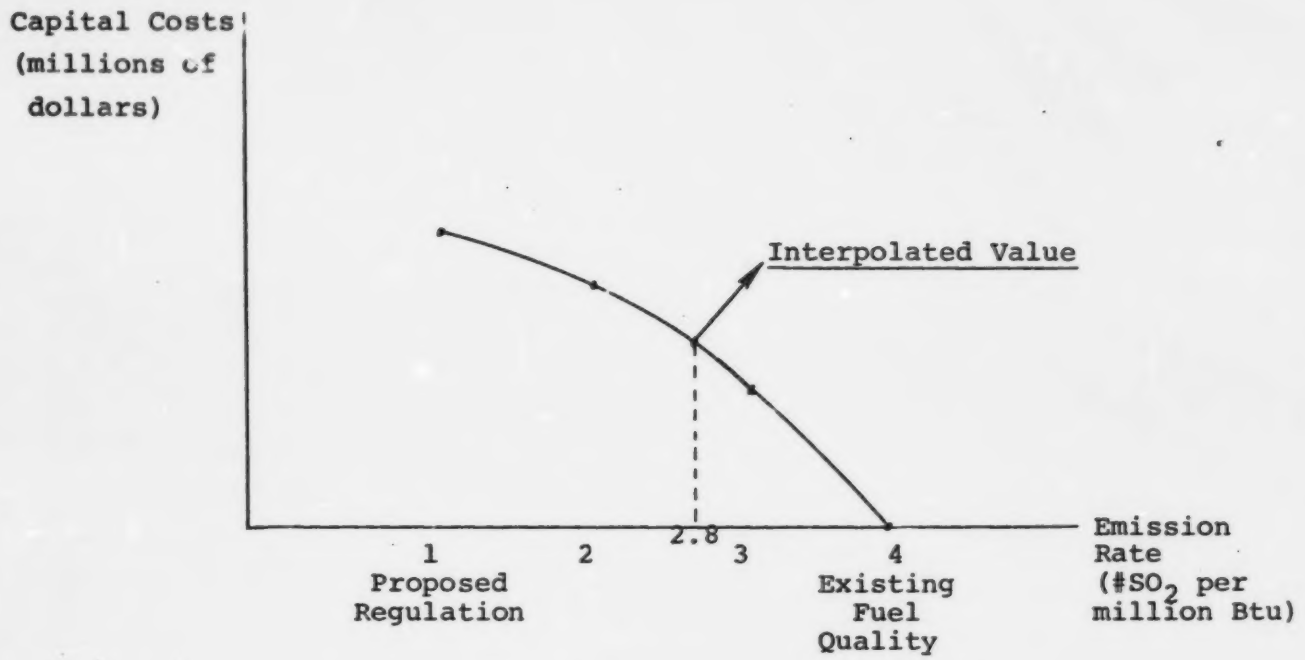
1/ See document #8 for control equipment costs and document #10 for coal prices.

FIGURE 4-1

COST CURVES FOR UTILITIES



such as a regulation of 2.8 #SO_2/MMBTU shown in Figure 4-1, were obtained by linear interpolation between the two nearest data points--in this case between 2 and 3 #SO_2/MMBTU. This approach generated a cost curve over the expected relevant range of regulations which might be evaluated.

This methodology applied to all non-fuel costs of control. Coal costs were based on a delivered price matrix to each plant which reflected price variations among 6 sulfur content classes for 7 potential sources of coal supply.

2. Costs Factors Considered

General cost factors were selected to reflect realistic utility practices and to insure consistency between the control strategy selection process and the subsequent utility economic impact evaluation presented in document #3.

a. Capital Costs and Taxes

The costs of capital for all investor owned utility systems in Ohio were assumed to be 17.3% based on an average mix of debt to equity.[1/] Depreciation was calculated on a straight line basis over the remaining life of the plant. Remaining life was either 110 years minus age in 1978 or 20 years, whichever is less. 40 years was the assumed maximum plant life and 1978 was a median date when control equipment would be installed. If remaining life was greater than 20 years, the amortization period was set at 20 years which is the approximate life of pollution control equipment.

1/ Unless otherwise documented, cost factors in this section were provided by Temple, Barker and Sloane to insure consistency with their analysis in document #3.

Investment tax credits were not considered since they are a credit only in the first year and were felt to be an insignificant cost factor over the life of the investment. Exclusion of this factor tends to overstate costs slightly.

Allowance for funds during construction (AFDC) includes interest cost during construction of the capital facility and is assumed to be included in the rate base at a cumulative cost equal to 10.4% of the installed capital cost of the facility.

The tax rate for taxes other than income tax were assumed to be 10.4%.

Table IV-1 shows an illustrative calculation of the implied annual cost of capital for the affected plant which would be passed on to the consumer. For an investment with a 20 year remaining life, 25% of the installed capital cost would be passed on as annual costs of capital.

b. Price Escalators

The price escalators were those used by TBS in document #3 to insure consistency between the two analyses. Table IV-2 contains these factors for capital, non-fuel operating and fuel costs as a ratio of the year used in the analysis to 1975 prices. 1978 was selected as an average of the price escalation for capital expenditures in the 1976-79 time frame. Operating and fuel costs were escalated to 1985 for reasons discussed earlier.

TABLE IV-1

ILLUSTRATIVE CAPITAL COST FACTOR
(20 Year Life)

$$\underline{\text{Capital Cost}} = \left[\frac{1 + \text{AFDC}}{\text{Useful life}} + \text{Cost of Capital}\right]\left[1 + \frac{\text{Tax Rate}}{1 - \text{Tax Rate}}\right]$$

$$= \left[\frac{1.104}{20} + .173\right]\left[1 + \frac{.104}{1 - .104}\right]$$

$$\underline{\text{Annual Capital Cost}} = .25$$

TABLE IV-2

PRICE ESCALATORS FOR UTILITY COSTS

Cost Category	Price Index (end year/ 1975)	End Year
Capital	1.35	1978
Operating Costs (pollution control)	1.7	1985
Coal Costs	2.6	1985

3. Replacement capacity

Requirements for new capacity are the result of power needs to operate pollution control equipment and to offset derates incurred when switching from high to lower sulfur coal. Since each plant was assumed to continue to generate the same gross amount of electricity as in 1974-75 (as discussed above), additional power needs to run control equipment would result in a reduction in net electricity generation (total generation minus internal plant uses). This reduction in net generation is assumed to be replaced by additional new generating capacity by 1985.[1/] The capital and operating costs of this replacement capacity are then added to the cost of the control strategy.

The new capacity is assumed to have a useful life of 33 years and AFDC at a higher rate of 16.87% of installed capital cost due to the longer construction period for power plants as compared to pollution control equipment. New plant costs in 1980 dollars were assumed to be $600 per kilowatt of capacity comprised of $525 plant cost plus a rough estimate of $75 for sulfur and particulate removal control costs. Operating costs (including fuel) for the new plants are assumed to be 23.3 mills per kilowatt hour in 1985.

4. Coal Cost and Coal Supply

Existing sources of coal supplies to each plant were derived based on Federal Power Commission Form 423 data for the period January 1 - October 31, 1975. The average delivered price per million BTU is calculated using the

---

1/Boiler derates have a similar effect on replacement demands except in this instance both fuel consumption and gross power generation at the affected plant decline according to the degree of derate.

following formula:

$$\text{Average existing price} = \sum_{i=1}^{7} P_i S_i$$

Where P_i = delivered price from region i to the plant[1/]

S_i = percentage of total coal BTU's consumed at the plant originating in region i

The volume of existing coal supplied from each supplier region to the plant is derived by multiplying the plant BTU consumption by the regional share (S_i) then dividing by the average heat value of 1975 shipments from that region to the plant to yield tons of supplies shipped from each supplying region.

C. Flue Gas Desulfurization

1. Overview of Cost Analysis Procedure

FGD costs are calculated for both regenerable and throwaway systems in the following manner:

- the applicable regulation is specified for each stack
- the required sulfur emission reduction is calculated and cost values interpolated
- the annual capital and operating costs of achieving the regulations are generated for both FGD systems

FGD cost estimates are prepared for each stack and are independent of any plantwide constraints since this control alternative assumes the plant continues to utilize existing sources of coal supplies.

1/ Derivation of these prices is discussed in document #10.

2. Factors Considered

FGD costs are based on a fixed sulfur removal efficiency of 85 percent combined with the assumption that only a portion of the stack flue gas stream needs to be treated to insure that the emission limits are satisfied.[1/] In effect, part of the stack gas is by-passed in order to reduce the costs of applying FGD to meet a specific regulation. Table IV-3 shows the factors considered in determining FGD costs for a specific regulation. Several factors warrant explanation.

a. Power Penalty (PENP)

This penalty accounts for the electricity required to operate the FGD equipment. Since gross power generation at the plant was assumed to be constant, the power required to operate the scrubber effectively derates the plant by reducing its net electricity generation (electricity available for final consumers). This power derate is assumed to require the installation of new capacity in the utility system. Thus, the capital, operating and fuel costs of this replacement capacity are added to FGD costs.

b. Steam Penalty (PENS)

Steam is also required to reheat the stack gas leaving the FGD units. This study assumed that while gross electricity output was fixed, excess boiler capacity existed. Thus, steam demands are met by increased fuel utilization at the plant without any power derate. This extra fuel use is included in the operating cost of FGD systems.

c. Economies of Scale

FGD costs can also vary depending upon how many units are installed at a plant. For example, sludge disposal costs per

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1/ See document #8 for further details.

TABLE IV-3

FACTORS IN FGD COST ANALYSIS

K	-	installed capital costs (millions of 1975 dollars)
CAP	-	rated capacity (megawatts)
CU	-	capacity utilization (.XX)
L	-	remaining useful life
PECOAL	-	price of existing coal supplies ($/MMBTU)
ABTU	-	annual fuel consumption (10^6BTU's)
OPCOST	-	non-fuel costs of operating FGD systems (millions of 1975 dollars)
PENP	-	power penalty of operating FGD (.XX of rated capacity)
PENS	-	steam demand required to operate FGD systems (.XX of rated capacity)
AK	-	annual capital costs (millions of 1985 dollars)
OM	-	annual operating costs (millions of 1985 dollars)
AC	-	annual capital and operating costs (millions of 1985 dollars)

kilowatt of installed FGD capacity decline as more units at the plant install FGD. Such economies of scale were taken into account in the FGD cost algorithm.[1/]

3. Cost Algorithm

Table IV-4 shows the formula for calculating the annual costs of FGD. Capital cost (K) and operating cost (OPCOST) are interpolated for the appropriate regulation as described above. Annual capital charges (AK) are then calculated as a function of an inflation factor converting from 1975 to 1978 dollars, the cost of capital, depreciation, and AFDC. The second term in equation (1) is the capital cost of replacement capacity to offset the power derate (PENP), equation (2) includes FGD operating costs inflated to 1985 dollars plus extra fuel costs due to the steam penalty plus the operating cost of replacement capacity. In equation (3), total annual costs are determined and adjusted for taxes (excluding income tax).

1/ Economies of scale were used to adjust costs as follows. First, for each plant the economies of scale factor (ESF) was set equal to:

$$ESF = \frac{\text{Cost of installing FGD at entire plant}}{\text{Cost of installing FGD individually for each stack summed over plant}}$$

If ESF = .8, then plantwide installation of FGD is 20 percent less expensive than installing FGD at each stack and ignoring economies of scale. Factors were calculated for both capital and operating costs. In calculating costs, the scale factor was interpolated linearly between a scale factor of 1.0 for 1 megawatt installed FGD to .8 for 100 percent FGD installation. This scale factor was then multiplied by the single stack FGD costs.

TABLE IV-4

COST ALGORITHM FGD

Equation (1)

$$AK = 1.35 * K * 10^6 * \left(.173 + \frac{1.104}{L}\right) + \overbrace{PENP * \left[\$600 * CAP * 1000 * \left(.173 + \frac{1.168}{33}\right)\right]}^{\text{Replacement Costs}}$$

Equation (2)

$$OM = OPCOST * 1.7 + \overbrace{PENS * (ABTU * PECOAL)}^{\text{Steam Penalty}} + \overbrace{PENP * (CAP * 1000 * CU * 8760 * 0.023)}^{\text{Power Derate}}$$

Equation (3)

$$AC = 1.117 * (AK + OM)$$

D. Low Sulfur Coal

1. Overview

In calculating the cost of the option of converting to lower sulfur coal, the first step is to determine the binding regulation. Under the assumption that utilities are only permitted one coal pile, then the regulation that must be satisfied is the most stringent regulation for any stack in the plant. For example, a plant may have 3 stacks with applicable regulations of 4.0, 3.5 and 1.0, #SO_2/MMBTU for these stacks. If this plant is to use low sulfur coal, then all stacks must utilize coal equal to or less than 1.0 #SO_2/MMBTU for the plant to be in compliance. The selection of the least cost source of low sulfur coal is a 5 step process outlined in Figure 4-2.

2. Factors Considered

In addition to the basic parameters already discussed under FGD costs, several factors specific to fuel switching are considered.

a. Upgrading Particulate Control Equipment

Capital and operating costs of upgrading particulate controls are incurred when the sulfur content of the fuel declines. This is necessary since a decline in SO_2 emission tends to reduce the collection efficiency of electrostatic precipitators. This additional cost is a function of the degree of sulfur removal but is assumed to be independent on the origin of the lower sulfur content coal.[1/]

b. Boiler Modification

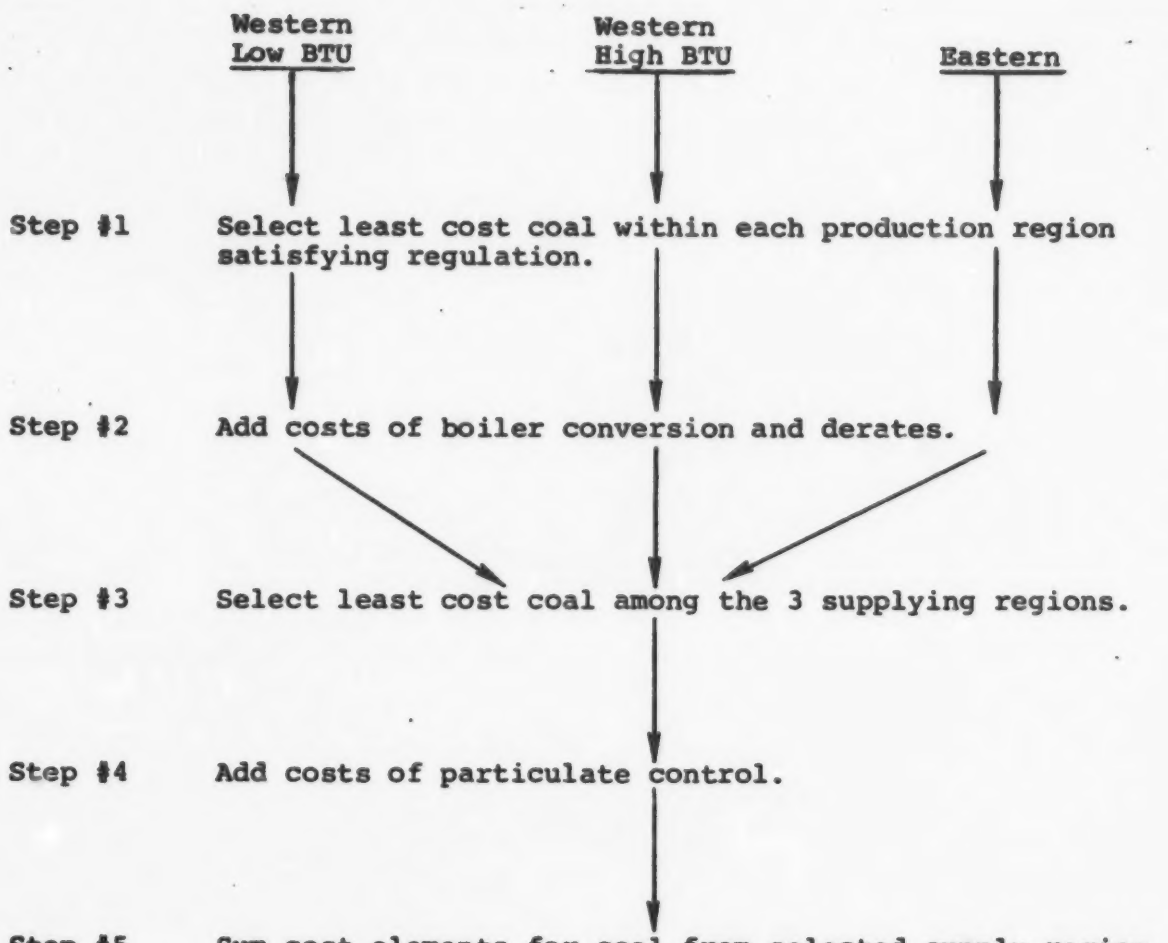
Converting to a lower sulfur content coal can require modifications to boilers or expanding pulverizer capacity.

c. Power Derates

1/ The study assumes plants to be in compliance with particulate regulations so that upgrading costs are only those related to SO_2 control.

FIGURE 4-2

SELECTION OF LOW SULFUR COAL STRATEGY


Western Low BTU
Western High BTU
Eastern
Step #1
Select least cost coal within each production region satisfying regulation.
Step #2
Add costs of boiler conversion and derates.
Step #3
Select least cost coal among the 3 supplying regions.
Step #4
Add costs of particulate control.
Step #5
Sum cost elements for coal from selected supply region.

Power derates analogous to those occuring when FGD is selected will also occur when switching to lower sulfur content coal. Switching to LSC always brings an attendent increase in power demands due to increased electricity required to operate the upgraded electrostatic precipitator. A second source of derates can occur when a unit switches to western coal. A combination of lower heat value, higher moisture content and other factors can effectively derate the boiler by reducing BTU energy input.[1/] To some extent, this can be offset by increasing tonnage throughout in an effort to maintain gross power generation at the plant. However, this derate cannot always be offset due to limitations on pulverizer capacity or other factors. Derates were calculated for each unit after allowing for offsets resulting from efforts to increase tonnage throughout.

These two sources of derates result in additional capital and operating costs for replacement capacity. The western coal derate also reduces BTU's of fuels consumed at the plant, resulting in a corresponding reduction of gross electricity generation at the plant.

3. Low Sulfur Coal Cost Algorithms

Table IV-5 contains the additional factors considered in deriving the incremental costs of lower sulfur coal. Annual capital costs reflect costs of pollution control equipment and replacement capacity. Operating costs include:

- costs of boiler and ESP
- operating and fuel cost of replacement capacity
- incremental fuel costs

1/ See document #8 for details.

TABLE IV-5

ADDITIONAL FACTORS CONSIDERED FOR THE LOW SULFUR COAL ALTERNATIVE

K	=	capital cost of boiler modifications and ESP upgrades
OPCOST	=	added boiler operating costs plus incremental ESP non-power operating costs
SLBD	=	boiler derate (% of capacity)
SLED	=	ESP power derate
PNCOAL	=	price of low sulfur coal

Table IV-6 shows the equations used to calculate the annual costs of switching to a lower sulfur content coal.

E. Blending

1. Overview of Logic

The option to blend allows plants to purchase some lower sulfur content coal to mix with existing coal supplies to satisfy sulfur emission limits. This alternative is particularly relevant for plants which require a relatively minor reduction in the sulfur content of their coal.

The logic of the choice of blending fuel is as follows:

- For each of the coal supply regions, coal supplies at or below the applicable regulation are identified.
- For each supply region a simple comparison algorithm determines whether it is cheaper to blend less of a more expensive lower sulfur content fuel than to blend in more of a less expensive coal which is higher in sulfur content. In effect, the higher price premium for lower sulfur content coal is weighed against the sulfur reduction obtained.
- This comparison results in the selection of the appropriate sulfur content coal to be blended for each of the major supply regions (western high-BTU, western low-BTU, eastern).

After these steps, the logic of the selection process is exactly the same as for low sulfur coal as depicted in Figure 4-2.

TABLE IV-6

COSTS OF LOW SULFUR COAL

Equation (1)

$$AK = K * 10^6 * 1.35 \left(.173 + \frac{1.104}{L}\right) + (SLBD + SLED) * \left[\$600 * CAP * 1000 * \left(.173 + \frac{1.168}{33}\right)\right]$$

Equation (2)

$$OM = OPCOST * 10^6 * 1.7 + (SLED + SLBD) * CAP * 1000 * CU * 8760 * .0233$$

$$2.6 * \left[PNCOAL * ABTU * (1-SLBD) - PECOAL * ABTU\right]$$

Equation (3)

$$AC = (AK + OM) * 1.117$$

2. Factors Considered

The parameters for coal blending are the same as for low sulfur coal except that additional costs for a blending facility are included. These costs include capital, operating and power demands. Power derates and other cost elements for low sulfur coal are applied according to the proportion of new lower sulfur coal supplies which are blended in with existing coal supplies. Particulate control equipment upgrades are the same as for low sulfur coal since costs of upgrading ESP devices are a function only of the sulfur emission reduction required (the ratio of the regulation to current coal quality).

3. Blending Cost Algorithm

Equations determining the annual costs of blending are essentially the same as for low sulfur coal except that:

- costs of the blending facility are added
- the incremental costs of low sulfur coal are calculated only for the percentage of coal BTU's blended with existing supplies

F. Coal Cleaning

1. Overview of Logic

An option was included to allow a coal cleaning facility to be constructed at the power plant site, sized to the coal consumption of the plant. The coal cleaning facility had to be of a minimum size to be feasible.[1/] It was assumed that only existing coal supplies would be washed.

2. Factors Considered

Coal cleaning costs are relatively straightforward, and

1/ See document #8 for further details.

include capital, operating costs and an energy penalty. While power required to operate the coal cleaning facility is negligible, there are significant BTU losses incurred in the cleaning process. Consequently, the quantity of fuel delivered to the plant must increase to offset BTU losses in order to maintain the same level of gross electricity generation. In fact, this option was never selected since it was always cheaper to clean coal at the mine site, thereby avoiding the cost of transporting BTU's to the plant which are then lost in the washing process.

3. Cost Algorithms

Table IV-6 shows the equations used to determine the costs of coal cleaning.

G. Combination Alternatives

1. Overview of Logic

The plant was allowed to select combinations of the options presented above to reflect application of FGD with washed coal, low sulfur coal and blended coal. These combinations were included to reflect realistic choices facing the utilities. In some cases, these combination options were the only means of achieving a stringent emission limit. For example, a plant currently using coal with a 5.0 $\#SO_2$/MMBTU sulfur content is required to comply with a regulation of 0.5 $\#SO_2$/MMBTU. Application of FGD to current coal would not achieve a sufficient emission reduction.[1/] Furthermore, low sulfur coal of a quality to satisfy this regulation is not available. Consequently, compliance must be achieved by a combination of control alternatives.

The combination of options is selected by an approximation technique which is described below for the option of low sulfur

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1/ The resultant emission rate would be .75 $\#SO_2$/MMBTU assuming a normal efficiency of 85 percent.

TABLE IV-6

COST ALGORITHM FOR COAL WASHING

Equation (1)

$$AK = K * 10^6 * \left(.173 + \frac{1.104}{L}\right) * 1.35$$

Equation (2)

$$OM = OPCOST * 10^6 * 1.7 + PEN * ABTU * PECOAL$$

Equation (3)

$$AC = (AK + OM) * 1.117$$

Where PEN = percent of BTU's lost in the washing process.

coal plus FGD. Suppose the plant's current sulfur content is 5.0 #SO_2/MMBTU and it is required to meet a regulation of 2 #SO_2/MMBTU for all stacks. The interval between 2-5 #SO_2/MMBTU is divided into deciles with a sulfur limit associated with each. Using the intermediate value of 2.6 #SO_2/MMBTU as an illustration, the least cost low sulfur coal is selected to meet that emission limit. Then annual costs of FGD are calculated, assuming that FGD must achieve an overall emission reduction of 0.6 #SO_2/MMBTU to achieve the regulatory requirement of 2.0 #SO_2/MMBTU. The annual costs of FGD and low sulfur coal are then summed to provide the cost of one combination option. This process is repeated for the other 9 intermediate sulfur limits. A similar procedure is followed for other combination options.

2. Cost Algorithms

The factors considered and the cost algorithms are exactly the same as described for the control alternatives discussed earlier.

SECTION V

CONTROL STRATEGY SELECTION AND COSTS

A. Introduction

There are presently 33 major electric power plants in Ohio operated by 8 investor-owned utility systems and 13 municipal and cooperative utilities. Together they account for a coal-fired capacity of over 23,000 megawatts and burn approximately 52 million tons of coal annually. The investor-owned utilities account for approximately 94 percent of this capacity and over 96 percent of the electricity generation in Ohio. For this reason the discussion focuses on the impacts of these investor-owned systems. 1/

This section summarizes the compliance strategies selected by the optimization methodology. It also summarizes the resulting increase in capital expenditures and annual costs.

B. Control Strategies Selected

The economic and energy impacts of the proposed and final regulations are primarily determined by the stringency of the regulations and the subsequent emission control strategy selected by the utilities to achieve compliance.

1. Proposed Regulation

Under the proposed regulation, essentially all of the coal fired capacity in Ohio would be out of compliance. Table V-1 shows the expected mix of control strategies selected by the plants. The anticipated choices reflect a roughly equal balance of FGD and low sulfur coal. It should be emphasized that the classification of utility capacity switching to "low sulfur coal" only implies shifting to a coal with a lower sulfur content in comparison with

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1/ The cost impacts on the municipal and cooperative utilities were estimated for the final regulation, see document #3.

current coal quality. For example, over one-half of the capacity shifting to lower sulfur content coal is expected to utilize medium and relatively high sulfur content coal, primarily from Ohio.[1/] The stringency of the proposed regulations is reflected by the estimate that 14 percent of utility capacity would have to both switch coal supplies and install FGD to comply with the regulations, primarily because FGD alone will not obtain sufficient sulfur removal to attain the applicable regulation. In addition, 39 percent of capacity would have to install FGD on current coal.

2. Final Regulation

Under the final regulation, only 19 plants accounting for slightly over one-half of rated capacity are completely or partially out of compliance. Thus, the more flexible form and lesser stringency of the final regulations would bring half of Ohio utility capacity into compliance. The mix of control strategies in Table V-1 reflects the lesser stringency of the regulations since only a small percentage of capacity requires both FGD and low sulfur coal to satisfy applicable emission limits.

C. Aggregate Cost Impacts

Compliance with the proposed or final regulations will require the utilities to increase capital expenditures and annual revenues. The increase in capital expenditures will be required for installation of pollution control equipment (scrubbers, blending facilities, precipitators, etc.) and for replacement of existing generating capacity which is derated as a result of the use of low sulfur coal or control equipment. The total annual cost, or annual revenue requirements, of the utilities would increase due to increased operating and maintenance costs, fuel premiums, in-

1/ See document #5 for a further discussion of the energy impacts of the regulations.

TABLE V-1

ANTICIPATED CONTROL STRATEGY SELECTION BY MAJOR COAL FIRED POWER PLANTS OF INVESTOR-OWNED UTILITIES

Control Strategy[1/]	Proposed Regulations			Final Regulations		
	Plants	Mw	%	Plants	Mw	%
Flue Gas Desulfurization	9	8,300	39	8	5,000	23
Low Sulfur Coal or Blending	11	9,100	42	10	6,100	29
FGD Plus Lower Sulfur Coal	4	3,100	14	1	300	1
Sub-Total	24	20,500	95	19	11,400	53
In Compliance	3	1,000	5	8	10,100[2/]	47
Total	27	21,500	100	27	21,500	100

1/ Where FGD is selected, the megawatt capacity reflects these units requiring some use of FGD. The actual megawatts of scrubbing equipment required depends upon the degree of emission reduction required and will be less than the rated megawatt capacity.

2/ Mw figure includes capacity of units in compliance at plant which have other units out of compliance.

terest and depreciation charges on capital, and income and property taxes.

The capital costs and annual increases in consumer charges shown in Table V-2 reflect the significant cost reductions brought about by refinements of the final regulations compared to the proposed regulations. Especially significant is the reduction in capital requirements of two-thirds or nearly one billion dollars as a consequence of revisions of the final regulations which reduced the capacity anticipated to require flue gas desulfurization from 11,400 to 5,300 megawatts.

Table V-2

ELECTRIC UTILITIES

COSTS OF SULFUR OXIDE REGULATIONS

(Millions of 1975 Dollars)

Alternatives	Total Increase in Capital Costs (1976-1979)	Required Increase in Annual Revenues in 1980
Proposed	1480	354
Final	542	130
Cost Reduction	938	224

1/ The above costs include only investor-owned utilities. Costs for municipal systems were estimated at $24 million of capital expenditures and a $3 million annual cost increase.

SECTION VI

SPECIAL STUDIES

A. Introduction

This section contains the results of sensitivity analyses which were performed during the preparation of the utility economic impact analysis.

The first analysis was designed to show the sensitivity of utility control costs to alternative sets of regulations. This analysis provided the basis for a recommendation that allowing stack specific emission limits to differ within plants would reduce the costs of achieving air quality standards.

The second analysis was designed to show the sensitivity of control strategy selection and costs to a different estimate of FGD costs.

Finally, the third analysis illustrates the sensitivity of cost estimates when the one coal pile assumption is relaxed, allowing the plant to use more than one quality of coal.

B. Sensitivity of Costs to Regulatory Structure

1. Issue Addressed

This special study arose out of informal discussion between EEA personnel and EPA staff involved in the process of establishing regulations to be promulgated by USEPA for the state of Ohio. It was pointed out that conceptually a set of stack specific regulations where emission limits differed among stacks was likely to result in lower costs than a flat regualtion - all stacks subject to the same emission limit. This cost savings appeared possible since some stacks may not require any control to achieve air quality standards. In addition, stacks within a plant differ with

respect to the cost of achieving the same emission limits as a consequence of differences in:

- remaining useful life
- capacity utilization rate
- size of unit
- stack specific parameters, such as difficulty of FGD retrofit

Furthermore, air quality modeling studies typically indicate a wide variation among stacks in the air quality contribution per pound of SO_2 emitted. Consequently, an approach utilizing both air quality modeling results and costs of control should result in a more complicated set of regulations which can be realized at lower cost.

Understandably, complicating the regulatory structure is not desirable unless there is evidence that significant cost savings would result. This study presented comparative cost analyses on a sample of seven isolated power plants to demonstrate that significant cost savings could be realized.[1/]

2. Regulations Compared

This analysis provided estimates of capital and annual costs of compliance for two sets of regulations.

Flat regulations. These regulations are based on a straight rollback approach determined by the new air quality modeling and updated plant data prepared by EPA. Since all stacks in a plant tend to utilize the same sulfur content fuel at present, application of an overall percentage emission reduction to achieve standards results in a flat regulation (i.e., the same regulation for

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1/ It should be emphasized that the development of more complex regulations becomes much less feasible for sources where other nearby plants also contribute significantly to the local air quality problem. Thus, the discussion here applies only to plants which are the predominant cause of potential air quality violations - typically isolated sources.

each stack). This approach is similar to that employed in the proposed regulations for isolated sources.

Least cost regulations. This set of regulations represents the emission limits which minimize the costs of achieving air quality standards. The development of these regulations is described below.

3. Development of Regulations

a. Flat Regulations

These regulations were derived by solving for the highest (least stringent) emission rate applicable to all stacks which would achieve air quality standards.

b. Least Cost Regulations

These regulations were developed by solving for a set of regulations which would minimize the annual costs of compliance. The approach combines cost of control estimates with air quality modeling results. Conceptually, this approach assumes that a set of stack specific regulations which equalizes the marginal costs of improving air quality for all stacks will minimize the total plant costs of compliance.

In order to accomplish this objective, alternative sets of regulations for the sample plants were costed subject to the following constraint.

$$AAQS-B = \sum_i a_i R_i$$

Where AAQS = the binding air quality standard

B = background air quality contributions caused by other sources

a_i = the ratio of air quality contribution per pound of SO_2 emitted per million BTU's for stack i

R_i = the emission limit for stack i stated in #SO_2/MMBTU

In effect, this constraining equation is based solely on air quality modeling results and relevant plant characteristics.

Costs of control were estimated for each set of regulations using the cost minimization model developed by Energy and Environmental Analysis, Inc. and discussed elsewhere in this document.

4. Results of Analysis

Table VI-1 presents the annual costs for a sample of power plants projected to be exceeding air quality standards. Table VI-2 presents similar results for capital expenditures. Table VI-3 presents an illustration of how the stack specific regulations were used to determine the costs for the flat and least cost regulations.

It should be emphasized that the costs presented herein were based on preliminary data on costs and air quality modeling. In several cases, parameters were modified prior to the promulgation of final regulations by EPA on August 27, 1976. These cost estimates should, consequently, be evaluated in terms of the comparative purpose of this study and do not necessarily reflect the final estimates of cost or appropriate regulations for this sample of plants.

The analysis clearly shows that if stack specific regulations were determined taking account of costs, the overall burden on the affected sources would be significantly less than if a flat regulation were to be adopted. The least cost regulations could result in an estimated 23.3 percent annual cost savings and an even larger 30.7 percent reduction in capital expenditures required to achieve air quality standards. Significant cost differentials between the flat and least cost regulations were estimated for all plants analyzed except Conesville and Philo. In the case of Conesville, the emission reduction required to achieve standards was so slight

that any set of stack specific regulations could achieve the standards at negligible cost. However, for Philo the emission reduction required was so great[1/] that a restrictive flat regulation structure appeared to be as cost effective as other more complicated regulation scenarios.

The analysis of the sample of plants where air quality modeling was available strongly supports the conclusion that consideration of cost factors in the derivation of stack specific regulations for isolated sources could result in both achievement of air quality standards and a significant reduction in the costs of achieving air quality goals. The analysis strongly supports the view that a flexible regulatory structure which allows the affected plants to set their own stack specific emission rates subject to one or more air quality constraints would minimize the costs of achieving air quality goals.[2/]

1/ For example, application of fuel gas desulfurization to current coal quality at an 85 percent sulfur removal rate would not provide sufficient control to achieve air quality standards.

2/ It should be emphasized that several air quality equation constraints may have to be imposed since shifting emission rates among stacks may result in a shift in the location of the maximum air quality impact point resulting from the plant emissions.

TABLE VI-1

Annual Cost
(millions of 1985 dollars)

PLANT NAME	MW[1/]	FLAT REG (1)	LEAST COST REG (2)	% COST SAVINGS $\frac{\text{Col (2)}}{\text{Col (1)}} \times 100 - 100\%$
Beckjord	1162	29.2	14.5	50%
Conesville	1537	0	0	---
Miami Fort	1510	27.8[2/]	24.3	12.5%
Philo	465	20.1	20.1	0%
Picway	145	4.0	2.5	37%
Poston	200	3.1	2.4	22%
Tidd	222	11.5	9.6	16.4%
TOTALS		95.7	73.4	23.3%

1/ Capacity exludes oil fired units.

2/ One stack was not controlled in the "flat reg case" due to its negligible air quality contribution. A "pure" flat reg would have cost $49 million to control.

It should be emphasized that the costs presented herein were based on preliminary data on costs and air quality modeling. In several cases, parameters were modified prior to the promulgation of final regulations by EPA on August 27, 1976. These cost estimates should, consequently, be evaluated in terms of comparative purpose of this study and do not necessarily reflect the final estimates of cost or appropriate regulations for this sample of plants.

TABLE VI-2

Capital Costs

(millions of 1975 dollars)

PLANT NAME	MW	FLAT REG (1)	LEAST COST REG (2)	% COST SAVINGS Col (2) / Col (1) X 100-100%
Beckjord	1162	16.6	7.4	55%
Conesville	1537	0	0	---
Miami Fort	1510	35.9	19.6	50%
Philo	465	25.6	25.6	0%
Picway	145	3.6	.4	89%
Poston	200	1.1	.8	27%
Tidd	222	10.5	10.9	- 3%
TOTALS		93.3	64.7	30.7%

It should be emphasized that the costs presented herein were based on preliminary data on costs and air quality modeling. In several cases, parameters were modified prior to the promulgation of final regulations by EPA on August 27, 1976. These cost estimates should, consequently, be evaluated in terms of comparative purpose of this study and do not necessarily reflect the final estimates of cost or appropriate regulations for this sample of plants.

TABLE VI-3

ILLUSTRATION OF
STACK-BY-STACK REGULATIONS FOR
ISOLATED POWER PLANTS

Plant Characteristics: 1257 Mw 4.28 #/MMBtu (existing sulfur content)

Stack	1	2	3	4	5
Mw Capacity	123	123	123	208	680
Capacity Factor	.73	.69	.74	.55	.63
Age (years)	23	33	22	20	4

Based upon modeling, the following equations must be satisfied to assure that the plant will comply with the 24-hour and 3-hour air quality standards. EL(i) is the emission limit for the i-th stack in pounds of sulfur dioxide per million Btu.

$$0.143(EL(1) + EL(2) + EL(3)) + 0.192EL(4) + 0.078EL(5) \leq 1.0$$

$$0.174(EL(1) + EL(2) + EL(3)) + 0.108EL(4) + 0.091EL(5) \leq 1.0$$

$$0.113(EL(1) + EL(2) + EL(3)) + 0.187EL(4) + 0.025EL(5) \leq 1.0$$

Using the least cost optimization model developed by Energy and Environmental Analysis, Inc. for the Ohio sulfur regulation economic impact analysis, several sets of regulations were evaluated.

	Emissions Evaluated					Costs (1975 $)	
Scenario	1	2	3	4	5	Capital	Annual
1	1.59	1.59	1.59	0.86	0.86	79.8	19.2
2	0.86	0.86	0.86	2.33	2.33	102.3	24.2
3	1.39	1.39	1.39	1.39	1.39	93.6	22.3
4	0.97	0.97	0.97	0.97	4.30	56.6	14.1

Relative to the flat rate (Scenario 3) which might have been chosen for the plant, the equations permit the utility to select optimal strategy such as Scenario 4. Capital and annual cost savings are approximately 40 and 37 percent.

C. Sensitivity of Results to FGD Costs

1. Background

The capital and operating costs per megawatt of capacity for FGD are critical inputs to this study. Since questions have been raised in the past regarding the validity of cost factors utilized by EPA, this section presents the results of a sensitivity analysis of FGD unit costs in terms of control strategy selection and associated costs of achieving compliance.

The results were obtained by increasing the capital costs provided in document #8 by 75 percent and FGD operating costs by 33 percent. Only unit costs for FGD were altered in this sensitivity analysis which tends to make low sulfur coal a more cost effective means of compliance.

2. Impact of Utility Costs

Table VI-4 presents a comparison of the costs of compliance contrasting the impact with higher FGD unit costs with the results discussed earlier in this report. Annual costs are approximately 31 percent higher under both proposed and final regulations if FGD unit costs are increased.

Capital costs are nearly 20 percent lower under the proposed regulations as utilities rely more on low sulfur coal rather than FGD to meet applicable regulations. Under the final regulations capital costs are not significantly different.

3. Impact on Control Strategy Selection

Table VI-5 compares the control strategies selected when FGD unit costs are raised above base case assumptions. Under the proposed regulations, capital costs drop sharply as the percent of utility capacity shifting to low sulfur coal increases from 42 percent in the base case to 73 percent if FGD unit costs are

TABLE VI-4

SENSITIVITY ANALYSIS OF UTILITY COSTS
TO FGD UNIT COSTS

(millions of 1975 dollars)

	Proposed Regulations		Final Regulations	
	Study Costs	Higher Costs	Study Costs	Higher Costs
Capital (1976-79)	1480	1227	542	561
Annual Costs	354	465	130	172

TABLE VI-5

SENSITIVITY ANALYSIS OF CONTROL STRATEGY SELECTION TO HIGHER FGD COSTS

(% of megawatts)

	Proposed Regulations		Final Regulations	
	Study Costs	Higher Costs	Study Costs	Higher Costs
Flue Gas Desulfurization	39%	21%	23%	10%
Lower Sulfur Coal or Blending	42%	73%	29%	43%
FGD Plus Low Sulfur Coal	14%	1%	1%	---
In Compliance	5%	5%	47%	47%

increased. This shift in control approaches also explains why overall annual costs do not increase as much as unit FGD costs since so many plants shift from FGD to low sulfur coal. Under the final regulations, capital costs are essentially unchanged while annual costs rise by 32 percent.

D. Cost Sensitivity Analysis of the One Coal Pile Constraint

1. Issue

As discussed earlier, the results of the cost minimization model presented in this study were prepared assuming that the average sulfur content of the coal consumed at a plant was identical for all stacks in the plant. Essentially, this assumption would not permit plants to establish more than one coal pile feeding fuel into all stacks. This assumption was made as a consequence of the lack of knowledge of boiler configurations and space limitations for coal pile storage at Ohio power plants. Since allowing more than one coal pile provides a plant with the added flexibility to differentiate the quality of coal fed into various stacks, the one coal pile assumption should tend to overstate the costs of control.

This special analysis was conducted on a sample of plants in order to illustrate whether costs of achieving air quality standards might be significantly lower where it was feasible to establish two coal piles.

2. Illustrative Plant

An example is shown for a plant with characteristics depicted in Table VI-6. In designing any set of regulations for this plant, it would be desirable to set a more stringent regulation applicable to Stack #3 since it

- contributes more to air quality levels per pound of SO_2 emitted,
- is fed by larger boilers whose control cost per kilowatt is less due to economies of scale,
- has a higher capacity utilization rate, thus allowing capital costs to be spread over a greater Btu level.

TABLE VI-6

EXAMPLE OF PLANT CHARACTERISTICS

	STACK NUMBERS		
	1	2	3
Mw Capacity	55	55	111
Capacity Utilization	44%	44%	82%
Air Quality Contribution (micrograms per #SO_2 per million Btu)	40	40	87

Existing sulfur content = 5.5 #SO_2/MMBtu for all stacks

Table VI-7 shows cost impacts for two regulation scenarios: a flat regulation and a regulatory structure which allows lower emission limits for stack #3. In both regulatory cases allowing the plant to use 2 coal piles reduces capital costs significantly (by over 40 percent) since the plant would find it economic to rely more on low sulfur coal. The annual costs of control are also lower when 2 coal piles are permitted, especially under regulatory scenario B where medium sulfur 2 #SO_2/MMBtu coal can be fed to stacks #1 and #2 while the third stack can use FGD with existing coal quality to satisfy regulations which achieve air quality standards. It should be noted that the cost savings of the variable stack specific regulations (scenario B) compared to the flat regulation (scenario A) are much greater in the two coal pile case compared to the one coal pile assumption.

3. Sensitivity Analysis of Costs

An evaluation of the potential cost savings of allowing multiple coal piles to a plant similar to the above illustration was conducted on a sample of 5 plants. Capital cost savings ranged from 30 to 80 percent and annual cost reductions obtained by allowing two coal piles of 10 to 20 percent were achieved at 3 of the 5 plants evaluated. For the remaining 2 plants, the cost savings were not significant.

The results, although the analysis did not include the extra costs of utilizing two coal piles, suggests that significant cost savings may be realized if the plant segregates its coal supplies to allow use of two coal qualities at the plant. Although the sample analysis cannot be considered conclusive, these partial results suggest that the estimates of the cost of compliance with sulfur emission limits used in this study may be significantly overstated.

TABLE VI-7

COST SENSITIVITY ANALYSIS OF
MULTIPLE COAL PILES

Regulation Scenario	Stack Number 1	2	3
A[1/]	1.58	1.58	1.58
B[1/]	2.0	2.0	1.3

Annual and Capital Costs
(millions of $1975)

Regulation Scenario	1 coal pile Annual	Capital	2 coal piles Annual	Capital
A	12.1	18.8	11.5	10.5
B	11.9	18.6	9.5	10.9

1/ Regulations in $\#SO_2$ per million Btu's.

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APPENDIX A

INFLATION IMPACT STUDY DOCUMENTATION

This appendix identifies the documents prepared to support the Inflation Impact Analysis of the sulfur oxide regulations prepared by the U.S. Environmental Protection Agency (EPA) for the state of Ohio.

Figure 1 identifies the supporting documents. Document #2 provides an overview of the study methodology and illustrates the depth of analysis contained in the study.

Impact Studies

Documents #3 and 4 are economic impact analyses of the utility and industrial sectors in Ohio. These reports address impacts on prices, output, employment and financial viability. Document #5 summarizes the energy impacts of the regulation in terms of the level of energy demand, shifts from coal to oil likely to occur as a result of compliance with the regulations as well as shifts in coal production patterns. In particular, this report focuses on whether coal production in Ohio, which is generally high in sulfur content, will be adversely impacted.

Cost Minimization

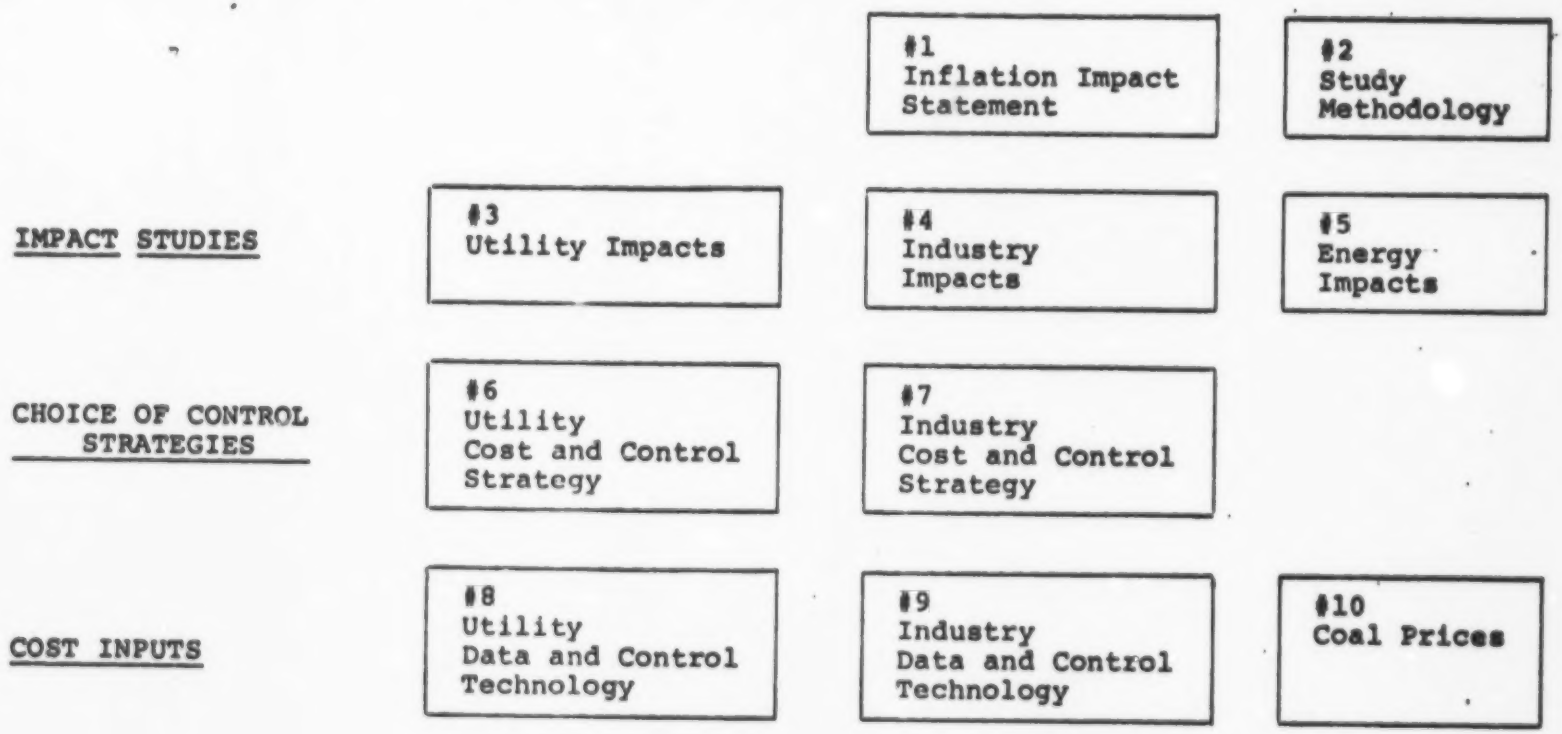
Documents #6 and 7 present the methodology for estimating costs of compliance and the choice of pollution control strategies. For both utility and industry, these supporting documents outline the cost minimizing strategies which provide the basis for the economic and energy impacts discussed in documents #3 - 5.

Cost Inputs

These final documents contain the basic data inputs to the study. Document #8 describes the pollution control technology options, their costs plus basic plant specific parameters which influence costs such as fuel consumption and boiler firing rates.

Figure 1

INFLATION IMPACT STATEMENTS SUPPORTING DOCUMENTS



Document #9 contains similar data on the industrial sector. Document #10 presents the derivation of coal prices employed in this study and used in both the industry and utility sector analysis. The focus is on the price premium of low versus high sulfur coal.

APPENDIX B

Plant/Company	Stack No.	Flat Stack Limit	Stack Option Equations
Miami Fort	2	0.30#/MBtu	
	3	3.40#/MBtu	
	4	3.40#/MBtu	
	5	5.50#/MBtu	
	6	1.2C#/MBtu Subject to NSPS	
Conesville	1	3.78#/MBtu	Equations (for 1, 2, 3)
	2		$1 \geq .1219\ EL_1 + .0906\ EL_2 + .0524\ EL_3$
	3		$1 \geq .0547\ EL_1 + .0327\ EL_2 + .0838\ EL_3$
	4	1.20#/MBtu Subject to NSPS	
Beckjord	1	2.02#/MBtu	$1 \geq .1426\ EL_1 + .1629\ EL_2 + .0667\ EL_3 + .0823\ EL_4 + .0122\ EL_5$
CG&E	2		$1 \geq .1252\ EL_1 + .1349\ EL_2 + .1003\ EL_3 + .1192\ EL_4 + .0155\ EL_5$
	3		$1 \geq .0337\ EL_1 + .0353\ EL_2 + .0382\ EL_3 + .0451\ EL_4 + .0709\ EL_5$
	4		$1 \geq .1334\ EL_1 + .1492\ EL_2 + .0740\ EL_3 + .0904\ EL_4 + .0247\ EL_5$
	5		$1 \geq .0249\ EL_1 + .0257\ EL_2 + .0283\ EL_3 + .0332\ EL_4 + .0841\ EL_5$
Philo	4	1.14#/MBtu	$1 \geq .3288\ EL_4 + .3301\ EL_5 + .1583\ EL_6$
Ohio Power	5		$1 \geq .3588\ EL_4 + .3605\ EL_5 + .1557\ EL_6$
	6		

Picway	3	4.11#/MBtu	$1 \geq .0846\ EL_3 + .0844\ EL_4 + .0745\ EL_5$
Col. and So.	4		$1 \geq .0573\ EL_3 + .0569\ EL_4 + .0934\ EL_5$
Ohio Electric	5		$1 \geq .0405\ EL_3 + .0402\ EL_4 + .1093\ EL_5$
Mad River	1	4.62#/MBtu (Coal) Stacks 1, 2, 3	Equations (for 1, 2, 3)
			$1 \geq .0995\ (EL_1 + EL_2) + .0173\ EL_3$
	2		$1 \geq .0498\ (EL_1 + EL_2) + .0516\ EL_3$
	3		$1 \geq .0735\ (EL_1 + EL_2) + .0190\ EL_3$
	4	1.00#/MBtu	
	5	(Turbines) Stacks 4&5	
Sammis		2.91#/MBtu	$1 \geq .1673\ EL_1 + .1670\ EL_2 + .0072\ EL_3 + .0022\ EL_4$
			$1 \geq .0557\ (EL_1 + EL_2) + .1106\ EL_3 + .0734\ EL_4$
Avon Lake	1	1.80$/MBtu Coal Units	$1 \geq .0891\ (EL_1 + EL_2 + EL_3 + EL_4) + .1198\ (EL_5 + EL_6) + .1578\ EL_7 + .1041\ EL_8$
	2		
	3	0.40#/MBtu Oil Units	
	4		$1 \geq .0548\ (EL_1 + EL_2 + EL_3 + EL_4) + .0676\ (EL_5 + EL_6) + .1067\ EL_7 + .1240\ EL_8$
	5		
	6		
	7		$1 \geq .0909\ (EL_1 + EL_2 + EL_3 + EL_4) + .1356\ (EL_5 + EL_6) + .1546\ EL_7 + .0799\ EL_8$
	8		
			$1 \geq .0943\ (EL_1 + EL_2 + EL_3 + EL_4) + .1241\ (EL_5 + EL_6) + .1606\ EL_7 + .0844\ EL_8$

Edgewater		3.40#/MBtu	
Lake Shore	4 5, 6, 7, 8	1.30#/MBtu Stack 4 1.90#/MBtu	
Cleveland Municipal		1.20#/MBtu	
Canal Road Steam Plant, CEI		1.20#/MBtu	
Hamilton Avenue Steam Plant, CEI		0.80#/MBtu	
Bayshore		1.30#/MBtu (Coal) 0.40#/MBtu (Oil)	
Acme		2.00#/MBtu (Coal) 0.80#/MBtu (Oil)	

Toledo-Edison Water St., Steam Plant		0.80#/MBtu	
Hamilton Municipal (Butler City)		1.40#/MBtu	
Tait		1.25#/MBtu (Coal) 0.65#/MBtu (Oil Diesels)	
Hutchings		1.20#/MBtu (Coal) 0.65#/MBtu (Oil Diesels)	Equation (for coal units only) $1 \geq .306\ EL_{27} + .297\ EL_{26} + .230\ EL_{25}$
Longworth St. OP&L		0.65#/MBtu (Oil Diesels)	
Third St. OP&L		0.65#/MBtu (Oil Diesels)	

Yankee Substation		0.65#/MBtu (Oil Diesel)	
Monument Substation		0.65#/MBtu (Oil Diesels)	
Gavin	1	9.50#/MBtu	
Kyger Creek	1 2 3	8.20#/MBtu	
Stuart DP&L	1 2 3 4	3.16#/MBtu	$1 \geq .0791 (EL_1 + EL_2 + EL_3 + EL_4)$
Woodcock		5.17#/MBtu	$1 \geq .0881\ EL_1 + .069\ EL_2$
Niles		5.41#/MBtu	$1 \geq .0923 (EL_1 + EL_2)$
Burger		12.90#/MBtu	

Toronto		8.J0#/MBtu	
Piqua Municipal		4.79#/MBtu	$1 \geq .0730\ (EL_1 + EL_2) + .0628\ EL_3$
Poston	1&2	3.94#/MBtu	$1 \geq .1607\ EL_1 + .0757\ EL_2$
Col. & So. Ohio	3	1.20#/MBtu	$1 \geq .1067\ EL_1 + .1220\ EL_2$
Electric		Subject to NSPS	$1 \geq .1315\ EL_1 + .1219\ EL_2$
Tidd	1	1.58#/MBtu	$1 \geq .1521\ (EL_1 + EL_2) + .3267\ EL_3$
Ohio Power	2		$1 \geq .1568\ (EL_1 + EL_2) + .3166\ EL_3$
	3		
Cardinal	1	4.76#/MBtu	$1 \geq .0668\ (EL_1 + EL_2) + .0763\ EL_3$
Ohio Power	2		
	3		
Muskingum River	1	6.48#/MBtu	$1 \geq .0902\ EL_1 + .0641\ EL_2$
Ohio Power	2		
East Lake	1	1.43#/MBtu	$0.143\ (EL_1 + EL_2 + EL_3) + 0.192\ EL_4 + 0.078\ EL_5 \_ 1.0$
CEI	2		$0.174\ (EL_1 + EL_2 + EL_3) + 0.108\ EL_4 + 0.091\ EL_5 \_ 1.0$
	3		$0.113\ (EL_1 + EL_2 + EL_3) + 0.187\ EL_4 + 0.025\ EL_5 \_ 1.0$
	4		
	5		

Appendix B (cont'd)

Ashtabula CEI	1 2 3 4 5	Above Status Quo	
Painsville	1 2	5.2 1.2	
East Palestine		4.4	
Gorge OG		2.1	
Beach St. OE		4.1	